



Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Department for Environmental Protection
Division for Air Quality

Revised Statement of Basis

Title V Proposed Permit, No. V-07-017

Cash Creek Generation, LLC.
Cash Creek Generating Station

Henderson, KY

Source I.D. #: 21-101-00134
Source A.I. #: 40285
Activity I.D. #: APE20060001

Reviewer: Combustion Section

November 14, 2007

Division of Air Quality

Table of Contents

TABLES	III
1. PROJECT SUMMARY	1
1.1 Coal Supply and Storage	1
1.2 Coal Grinding and Slurry Preparation	2
1.3 Air Separation	2
1.4 Gasification	2
1.5 Syngas Cleaning	3
1.6 Power Generation	4
1.7 Ancillary Equipment	4
1.7.1 Auxiliary Boiler	4
1.7.2 Cooling Water System	4
1.7.3 Wastewater Treatment	4
1.7.4 Fire Protection System	5
1.7.5 Natural Gas Supply	5
1.8 Sulfur Recovery	5
2. EMISSIONS ANALYSIS	5
2.1 Initial Compliance Demonstration	8
3. APPLICABLE AND NONAPPLICABLE REGULATIONS	8
3.1 Prevention of Significant Deterioration (PSD)	8
3.2 New Source Performance Standards (NSPS)	9
3.3 Maximum Achievable Control Technology Standards (MACT)	11
3.4 Compliance Assurance Monitoring (CAM)	11
3.5 Phase II Acid Rain Permits	11
3.6 Title V Operating Permit	12
3.7 State Regulations	12
3.8 Non-Applicable Regulations	13
4. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW	14
4.1 BACT Overview	14
4.2 Step 1 - Identify All Control Technologies	14
4.2.1 Generating Technology Analysis and Selection	15
4.2.2 Fuel selection	15
4.2.3 Control Technology Options	16
4.3 Step 2 - Technical Feasibility Analysis	17
4.4 Step 3 - Ranking of the Remaining Control Technologies	17
4.5 Step 4 - Top Down Evaluation of Control Options	18
4.5.1 Particulate Matter	18
4.5.2 Sulfur Dioxide and Sulfuric Acid Mist (IGCC)	20
4.5.3 Oxides of Nitrogen (IGCC)	25
4.5.4 Carbon Monoxide (IGCC)	25
4.6 Step 5 - Select BACT	27
5. AIR QUALITY IMPACT ANALYSIS	28
5.1 Modeling Methodology	29
5.2 Modeling Results	30
5.2.1 Class II Area Impacts	30
5.2.2 Class I Area Impacts	31

6.	ADDITIONAL IMPACTS ANALYSIS	33
	6.1 Growth Analysis	34
7.	CONCLUSIONS AND RECOMMENDATIONS	34

Tables

<i>Table 2-1 Maximum Potential to Emit.....</i>	<i>6</i>
<i>Table 2-2 Emission Limitations Proposed by Applicant.....</i>	<i>6</i>
<i>Table 2-3 Emission Limitations Proposed by Applicant (continued).....</i>	<i>7</i>
<i>Table 2-4 Emission Limitations Proposed by Applicant (continued).....</i>	<i>7</i>
<i>Table 3-1 Subpart Da Emission Limits</i>	<i>9</i>
<i>Table 4-1 Emissions Increase vs. Significant Levels</i>	<i>14</i>
<i>Table 4-2 Comparison of PC, CFB, and IGCC Emission Rates.....</i>	<i>15</i>
<i>Table 4-3 Proposed Emission Rates</i>	<i>15</i>
<i>Table 4-4 Possible Control Strategies & Technologies.....</i>	<i>16</i>
<i>Table 4-5 Summary of Control Technologies.....</i>	<i>17</i>
<i>Table 4-6 Summary of Most Stringent Limits for Existing and Proposed IGCC Sources.....</i>	<i>18</i>
<i>Table 4-7 Ranking of Control Technologies by Effectiveness</i>	<i>18</i>
<i>Table 4-8 SO₂ and H₂SO₄ Emission Control Options.....</i>	<i>21</i>
<i>Table 4-9 Average Cost Effectiveness Using the Uncontrolled Baseline Rate</i>	<i>23</i>
<i>Table 4-10 Average Cost Effectiveness Using the Wabash Baseline Rate.....</i>	<i>24</i>
<i>Table 4-11 Average Cost Effectiveness Using the MDEA Baseline Rate.....</i>	<i>24</i>
<i>Table 4-12 NO_x Emission Control Options</i>	<i>25</i>
<i>Table 4-13 BACT Determination for the Combustion Turbines</i>	<i>27</i>
<i>Table 4-14 BACT Determination for Material Handling.....</i>	<i>28</i>
<i>Table 4-15 BACT Determination for Cooling Tower.....</i>	<i>28</i>
<i>Table 4-16 BACT Determination for Auxiliary Boiler</i>	<i>28</i>
<i>Table 4-17 BACT Determination for Fire Pump.....</i>	<i>28</i>
<i>Table 5-1 Startup Emissions (Thermal Oxidizer Modeled).....</i>	<i>29</i>
<i>Table 5-2 Ambient Table</i>	<i>30</i>
<i>Table 5-3 Applicants Modeled Predicted Impacts</i>	<i>30</i>
<i>Table 5-4 Refined Modeling Results.....</i>	<i>31</i>
<i>Table 5-5 Class I Modeling Results - Normal Operations</i>	<i>32</i>
<i>Table 5-6 Class I Modeling Results - Startup.....</i>	<i>33</i>

1. PROJECT SUMMARY

The proposed facility will be located southwest of Owensboro, Kentucky, on Kentucky State Highway 1078 in Henderson County (37:42:10 N Latitude, 87:24:50 W Longitude). On May 4, 2006, Cash Creek Generation, L.L.C (Cash Creek) filed an application for a PSD/Title V air permit to construct a nominal 770 megawatt (MW) electric generating facility using Integrated Gasification Combined Cycle (IGCC) technology. On June 19, 2006, the Division issued a notice of deficiency. The response was filed on August 9, 2006, and included revised application forms. A second notice of deficiency was issued on September 20 and responses were filed on October 12 and November 11, 2006. Application was declared complete on March 29, 2007.

The IGCC process will use coal to produce synthesis gas (syngas) as the primary fuel (natural gas is a secondary fuel) to fire two, GE7FB series combustion turbines in combination with heat recovery steam generating (HRSG) units and a steam turbine to produce a nominal 770 MW (net output of 630 MW) of electricity. The syngas mainly consists of hydrogen gas and carbon monoxide. The two GE combustion turbines will operate in combined cycle mode, such that heat from the combustion turbines will be recovered in heat recovery steam generators (HRSG) and a steam turbine unit which also produces an additional 306 MW of electricity. The balance of the facility includes additional equipment necessary to start-up, maintain and operate the facility and which consumes approximately 140 MW for a net output of 630 MW of electricity to the grid.

This permit authorizes construction of two gasifiers. The proposed gasifiers will operate using the GE (formerly Chevron Texaco) oxygen-blown, entrained flow process. This process includes coal slurry and oxygen feed systems, gasifier reaction chambers, and syngas cooling.

Primary operations include:

- coal supply and storage
- coal grinding and slurry preparation
- air separation
- gasification
- syngas cleaning and sulfur recovery
- power generation

Each of these operations are summarized from the application below.

1.1 Coal Supply and Storage

The primary coal supply is expected be provided by the Patriot Coal Company, which operates an existing underground and surface mining and processing operation adjacent to the Cash Creek location. The coal will be delivered by a conveyor from the mine to an onsite receiving transfer-house. The coal is then transferred to a second 42-inch conveyor and transported to a second transfer house. This second transfer house directs the coal to long-term storage (90,000 ton capacity) or feeds it directly to the grinding and slurry preparation system. Coal may also be supplied by barge from other coal sources. Coal received by barge will be off loaded and transported by a conveyor to the receiving transfer-house.

1.2 Coal Grinding and Slurry Preparation

The grinding and slurry preparation system is designed to process coal based on a maximum rate of 800 tons per hour. Coal is transferred from the supply belt to a weight feeder that meters coal into a rod mill, which contains steel rods that crush the coal as the mill rotates at a constant speed. Rotation of the mill also facilitates blending of water and coal to produce fuel slurry. Process water is used in the mill with fresh makeup water. Using process water allows entrained coal and slag fines to be recycled in the fuel slurry. The slurry exits the mill through a coarse trammel screen into an agitated discharge tank. Slurry is then pumped to the top of the run tank. Before entering the tank it is screened a final time to remove any oversize contaminants or coal that might damage the gasifier slurry feed pump. Slurry storage tanks are continuously agitated to prevent plugging and maintain the concentration of the slurry. Slurry flows by gravity to the suction of the gasifier feed pump for transport to the gasifier feed injector.

1.3 Air Separation

-In the air separation block, air is cryogenically separated into oxygen and nitrogen. The oxygen is mixed with the coal slurry as the fuel feed to the gasification block. The nitrogen is used in the power block to lower gas turbine temperature and reduce NO_x emissions.

The main air compressor supplies compressed ambient air to a temperature swing absorption system to remove moisture and carbon dioxide, which is necessary to prevent freezing. Dry air is then routed to the main heat exchanger of the cryogenic section, where the air is cooled prior to entering distillation columns. Refrigeration for the separation process is supplied by a compander, using liquid nitrogen. The cryogenic distillation occurs in two columns, one operating at elevated pressure and the other at reduced pressure.

Diluent nitrogen is supplied to the combustion turbines by a multistage compressor. Similarly, high-pressure oxygen is needed for the gasifier feed and is supplied by a separate multistage compressor. Small amounts of low-pressure oxygen and nitrogen gases are also needed for other operations at the facility including the scrubbing operation. Withdrawing the gases prior to entering the compressors provides these low-pressure gases. Any impure nitrogen may be used as purge gas for the gasifiers.

1.4 Gasification

The gasifier block uses coal slurry/oxygen feedstock to produce syngas with a heating value of approximately 250 Btu/scf. The gasifier block will have two gasification units. Each unit will be designed to produce 50% of the syngas required when operating at maximum load.

Fuel is fed to the gasifiers through a process feed injector, which is designed to mix the coal slurry and oxygen and optimize dispersion into the gasifier at extremely high pressure and temperatures between 2300° and 2700° F. These conditions in the gasifier promote reactions which produce three major products: syngas, fine slag, and a coarse vitreous slag.

As the syngas exits the gasifier it passes through a radiant syngas cooler that produces high-pressure steam and increases efficiency and reliability by recapturing up to 15% of the fuel's heating value. Prior to leaving the gasifier, syngas passes over and through a water pool located at the bottom of the unit that enhances collection of the entrained slag.

The syngas produced in the gasifiers is rich in hydrogen, carbon monoxide, water vapor, and carbon dioxide. There are also lesser amounts of hydrogen sulfide, carbonyl sulfide, methane, argon, nitrogen, VOCs, acid gas and other trace components. Further processing is required to remove impurities.

Fine slag comprises unreactive mineral compounds and fuel particles that are not completely gasified (unburned carbon). This material is carried from the gasifier with the exiting syngas and must be removed prior to entering the acid gas removal system. The syngas is scrubbed with water to remove entrained particulates. The dirty or "black" scrubbing water is flashed to lower temperature and pressure and concentrated in the fine slag handling section. This concentrated slurry is then recycled to the gasification section.

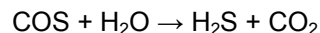
Slag is the mineral and ash matter that does not convert to syngas and is too heavy to be transported by the exiting syngas. A portion of this material melts in the high temperatures of the gasifier and flows to the bottom of the gasifier. It is removed from the gasifier through a lock-hopper. The slag is then transported to the slag handling operations. The slag is dewatered and transported by truck for sale as a by-product or to onsite landfills for storage. The slag ultimately solidifies into a stable glassy frit with very small amounts of residual carbon.

1.5 Syngas Cleaning

The syngas is scrubbed to remove particulates, treated to remove mercury and then enters an acid removal process. The acid removal stage removes sulfur compounds and produces molten elemental sulfur as a by-product.

The syngas passes through a multistage scrubbing process. This provides contact scrubbing with water and further removes entrained fine slag (flyash) from the syngas. It is during this scrubbing step that hydrogen chloride (HCl) is removed. The saturated syngas exiting the scrubber is then sent to the carbonyl sulfide (COS) hydrolysis reactor.

A small percentage of the coal slurry is converted to COS during the gasification process. The acid removal system is unable to remove COS from the syngas, so it must be converted to a form that can be removed to avoid a significant increase in sulfur dioxide (SO₂) emissions from the combustion turbines. Using a superheater followed by a catalyst reactor, conversion of COS to hydrogen sulfide (H₂S) is possible by the following chemical reaction:



The syngas then passes through a series of heat exchangers called the Low Temperature Gas Cooling (LTGC) system that cools the syngas to near ambient temperature prior to entering the mercury removal section. The cooled syngas passes through a carbon bed that removes mercury as well as other trace pollutants.

After passing through the carbon bed the syngas is directed to the acid gas removal system. This system uses Selexol[®] solvent in a tray absorber to remove in excess of 99% of the H₂S from the syngas. The exact level of removal is dependent on the specific operating conditions and fuel characteristics. The syngas enters through a valve in the bottom of the H₂S absorber module and passes up through the absorber column. The Selexol[®] water solution is sprayed from the top of the column. The trays in the column increase the residence time of the gas and liquid interface allowing a high degree of H₂S transfer to the Selexol[®] solution. The H₂S rich Selexol[®] exits the bottom of the tower and is sent to a stripping column.

The clean syngas exiting the absorber passes through a knockout drum and demister to remove any entrained solvent. The syngas is then preheated by passing through the highest temperature LTGC exchanger. The syngas leaves the LTGC exchanger and is moisturized before being sent to the combustion turbines.

1.6 Power Generation

The cleaned syngas is then supplied to the power block where it fuels the two combustion turbines to produce an estimated nominal 464 MW. Heat Recovery Steam Generators are then used to produce steam from the turbine exhaust gases. This steam is combined with steam from the gasification and scrubbing processes, and expanded in a steam turbine to produce an additional 306 MW. The air separation unit and other operations at the facility are anticipated to consume approximately 140 MW, resulting in an estimated 630 MW net output of electricity to the bulk power grid.

1.7 Ancillary Equipment

The balance of the facility includes additional pieces of equipment that are necessary for start-up, maintaining and operating the facility.

1.7.1 Auxiliary Boiler

A natural gas fired boiler, rated at 278.8 MMBtu/hour and producing 200,000 lb/hr steam at 150 psig, is used to preheat the air separation unit and radiant section of the gasifiers and purging the gasifiers during start-up. This boiler is designed to only operate during start-up of the gasifiers. Operation of the boiler is limited to less than 500 hours per year.

1.7.2 Cooling Water System

A mechanical draft multi-cell cooling tower equipped with mist eliminators, distribution piping, and pumps will supply cooling capacity for the power block and air separation unit.

1.7.3 Wastewater Treatment

Wastewater from the gasification block is collected in a blow-down/reaction tank. Blowers are used to aerate the wastewater in reaction tanks where chemicals are added to adjust the pH and assist with the coagulation and flocculation in a clarifier. Precipitated and suspended solids are collected and removed from the clarifier in a sludge blow-down process. The sludge blow-down is further dewatered in a thickener. Overflow from the thickener is returned to the clarifier. Sludge blow-down from the thickener is routed through a filter press where it is dewatered and produces a suitable solid for disposal in a landfill. Overflow from the clarifier is treated by additional chemical feed then routed to a 300,000 gallon demineralized water storage

tank that is used to supply demineralized water to the gasification block.

Wastewater from the power block drains is routed through an oil-water separator. The water stream from the oil-water separator is discharged to the cooling tower. Blowdown from the cooling tower will be discharged to the Green River¹.

1.7.4 Fire Protection System

The facility design includes fire water supply from a raw water storage tank, fire protection pumps, and fire water piping to the air separation unit, gasification block (including the gas clean-up area) and power block.

1.7.5 Natural Gas Supply

The facility design also includes a natural gas backup supply to the power block boundary. This supply includes a pressure regulating and metering station. The natural gas will be supplied to the facility by pipeline.

1.8 Sulfur Recovery

There are three types of sulfur recovery units in use or permitted for IGCC plants. A permit has been issued recently for use of a CrystaSulf system. CrystaSulf uses a proprietary nonaqueous process where gaseous hydrogen sulfide (H₂S) is converted to solid crystals of pure elemental sulfur. Secondly, permits have been issued for systems that recycle the overhead of a one stage Claus unit back to an Acid Gas Removal unit. The applicant has proposed the most common type of unit, where the reduced sulfur off-gas is treated with thermal incineration prior to venting to the atmosphere. Thermal treatment produces a moderate amount of NO_x and SO₂.

The H₂S rich Selexol[®] solution enters a tray tower stripping column. The Selexol[®] is treated to release the H₂S and then recycled for use in the absorber. The H₂S is sent to the sulfur recovery system where liquid sulfur is recovered in a Claus Process. The Claus process requires treating of the tail gas, which usually contains mostly H₂S and SO₂ but may contain traces of COS, CS₂ and elemental sulfur vapors. The tail gas is routed to a tail gas treatment (TGT) unit where the majority of the sulfur is recovered. The overhead of the TGT Unit is sent to a thermal oxidizer where the remaining H₂S and reduced sulfur are converted to SO₂ and any entrained solvent is destroyed before being emitted to the atmosphere.

2. EMISSIONS ANALYSIS

Pollutant emissions are produced by cleaning and combustion of syngas in the combustion turbines as well as produced by ancillary equipment including both point sources (Combustion Turbines, Thermal Oxidizer [for acid gas removal and sulfur recovery tail gas treatment], Cooling Tower, Flare, Coal Handling, Auxilliary Boiler and Emergency Fire Pump) and fugitive sources (Vehicular Traffic and Fuel Piles).

Pollutant emissions of the plant were based on

- 8760 hours per year of operating time unless stated differently
- 100% load capacity unless stated differently
- rated heat content for syngas is 251 Btu/scf and for natural gas is 1000 Btu/scf
- BACT limits established in section 4 of the application or emission factors noted in the calculations.

¹ A separate wastewater permit is required.

Table 2-1 Maximum Potential to Emit

Source Description	Emission Rates in tons/year						
	CO	VOC	NO _x	PM ₁₀ filterable	PM ₁₀ Total	SO ₂	H ₂ SO ₄
Combustion Turbines	919.9	28.1	628.6	161.2	411.6	299.2	66.44
Tail Gas Treatment-Thermal Oxidizer	41.5	2.8	71.9	2.8	2.8	91.2	
Flare	0.2	0.02	0.21	0.01	0.01	0.01	0.01
Cooling Towers				0.22			
Fuel Handling				0.14			
Coal Storage Pile				1.56			
Slag Storage Pile				1.20			
Oil-Water Sep							
Haul Roads				0.20			
Auxillary Boiler	2.6	0.3	2.5	0.5	0.5	0.4	0.1
Fire Pumps	0.05	0.01	0.06	0.01	0.01	0.01	0.01
Total	964.22	31.2	703.3	167.8	414.9	390.8	66.5

The following tables summarize the emission limitations proposed by Cash Creek

Table 2-2 Emission Limitations Proposed by Applicant

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION BASED ON CT HEAT INPUT	EMISSION LIMITATION BASED ON GASIFIER HEAT INPUT
HRSG1 & HRSG2	Combustion Turbine 1 & 2 (each)	PM ₁₀ filterable (syngas & Natural gas) PM ₁₀ Total	0.0085 lb/MMBtu 0.0217 lb/MMBtu	0.0063 lb/MMBtu filterable (BACT) 0.0161 lb/MMBtu Total
		Opacity	20%	20 %
		CO – syngas	0.0485 lb/MMBtu	0.036 lb/MMBtu
		CO - natural gas	0.0449 lb/MMBtu	
		NO _x syngas	0.0331 lb/MMBtu	0.0246 lb/MMBtu
		NO _x natural gas	0.0246 lb/MMBtu)	
		SO ₂ – syngas	0.0158 lb/MMBtu	0.0117 lb/MMBtu (BACT)
		SO ₂ - natural gas	0.001 lb/MMBtu	
		VOC – syngas	0.0015 lb/MMBtu	0.0011 lb/MMBtu
		VOC natural gas	0.0017 lb/MMBtu	
		H ₂ SO ₄ – syngas	0.0035 lb/MMBtu	0.0026 lb/MMBtu (BACT)
		H ₂ SO ₄ - natural gas	0.0001 lb/MMBtu	
		Hg – syngas		20 x 10 ⁻⁶ lbs/MWh
		Hg - natural gas		2.6 x 10 ⁻⁴ lbs/MMscf*

*AP-42 (7/98) (BACT not required)

Table 2-3 Emission Limitations Proposed by Applicant (continued)

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION
AUXB	Auxiliary Boiler, 278.8 MmBTU, 500 hours/year operating limit	PM/PM10	0.007 lb/MMBtu (BACT)
		Opacity	20% opacity
		SO ₂	0.006 lb/MMBtu (BACT)
		NO _x	0.036 lb/MMBtu (BACT)
		VOC	0.004 lb/MMBtu
FP	Emergency Fire Pump	PM/PM10	0.019 lb/MMBtu (BACT)
		CO	0.084 lb/MMBtu (BACT)
		SO ₂	0.0006 lb/MMBtu (BACT)
		NO _x	0.1 lb/MMBtu (BACT)
		VOC	0.0055 lb/MMBtu)
Coal Handling System:			
THDC33	Transfer House #1 Baghouse	PM/PM10	20% opacity *
THDC34	Transfer House #2 Baghouse	PM/PM10	20% opacity *
CDRC35	Coal Reclaim Baghouse	PM/PM10	20% opacity *
Fugitive Emission Sources:			
CAREA 1	Dead Coal Storage Pile	PM/PM10	no visible emission crossing the property line
38F	Barge Unloading	PM/PM10	no visible emission crossing the property line
CAREA 2	Coal Stacker	PM/PM10	no visible emission crossing the property line
CT1-10	Cooling Tower, Cell 1 through Cell 10	PM/PM10	0.0005% Drift Eliminators
	Slag Loadout	PM/PM10	No visible emissions crossing the property line
PAREA 1	Paved Haul Roads	PM/PM10	No visible emissions crossing the property line
AREA2	Slag Landfill	PM/PM10	No visible emissions crossing the property line

*Opacity is a surrogate for PM BACT

Table 2-4 Emission Limitations Proposed by Applicant (continued)

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION
FLARE1	Flare 3 pilot	PM ₁₀ filterable	0.000931 lb/hr
		PM ₁₀ Condensable	0.00279 lb/hr
		SO ₂	0.000294 lb/hr
		NO _x	0.049 lb/hr
		CO	0.0412 lb/hr
		VOC	0.0027 lb/hr
TO 30	Thermal Oxidizer	PM/PM10	0.63 lb/hr
		SO ₂	20.82 lb/hr
		NO _x	16.41 lb/hr
		CO	9.46 lb/hr
		VOC	0.63 lb/hr

2.1 Initial Compliance Demonstration

Proposed sources are required to demonstrate compliance by performance testing within 60 days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities. The combustion turbines and auxiliary boiler shall be required to be performance tested for pollutants by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet or U.S. EPA as follows:

Emission Units 01, and 02 shall be performance tested initially for compliance with the emission standards for PM/PM₁₀ (filterable and condensable); sulfur dioxide (SO₂); nitrogen oxides (NO_x); and carbon monoxide (CO), VOCs, mercury; and H₂SO₄, and fluorides.

Emission Unit 03 shall be performance tested initially for compliance with the emission standards for PM/PM₁₀ (filterable); nitrogen oxides (NO_x); and carbon monoxide (CO),

<u>Pollutant</u>	<u>Reference Method</u>
Particulate matter	Method 201 and Method 202
Opacity	Method 9
Sulfur dioxide	Method 6
Nitrogen oxides	Method 7
Carbon monoxide	Method 10
VOC	Method 25A and 18 if needed

Due to the limited amount of operational experience with IGCC units of this size and complexity, the Division has concluded that it is not unreasonable to include a waiver of the start-up and shutdown quantities and duration for the first year of operation of the facility.

3. APPLICABLE AND NONAPPLICABLE REGULATIONS

This section presents a discussion on the air quality regulations.

3.1 Prevention of Significant Deterioration (PSD)

401 KAR 51:017, Prevention of Significant Deterioration (PSD) of air quality, applies to the construction of a new major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42. U.S.C. 7407(d)(1)(A)(ii) and (iii). Cash Creek is a "Major stationary source" as defined in 401 KAR 51:001, Section 1(120)(b) for the PSD program because it is a fossil fuel-fired steam electric plant of more than 250 MMBtu per hour heat input and will emit, or has the potential to emit, 100 tons per year or more of a regulated NSR pollutant. Pursuant to 40 CFR 81.318 the facility will be located in a location that is "Better than national standards" or "Unclassifiable/Attainment" for all pollutants.

Therefore, Cash Creek is subject to PSD requirements. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR 60, 61, and 63.
3. Air quality impact analysis.

4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

3.2 New Source Performance Standards (NSPS)

The Clean Air Act of 1970 directed U.S. EPA to establish New Source Performance Standards, or NSPS, for specific industrial categories. There are three NSPS applicable requirements to the Cash Creek project. In some cases the emission limit or technology standard based on these and other applicable regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review). However, any specific testing, monitoring, record keeping, and reporting requirements contained in these regulations will still have to be met by the source in addition to any requirements under PSD.

40 CFR 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units (incorporated by reference in 401 KAR 60:005 Section 3(c))

40 CFR Part 60, Subpart Da requires all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 MMBtu/hour for which construction is commenced after September 18, 1978 (44 FR 33613, June 11, 1979) to meet limitations on emissions of PM, SO₂, and NO_x.

Table 3-1 Subpart Da Emission Limits

POLLUTANT	EMISSION LIMIT	AVERAGING BASIS
Opacity	20% except for one 6-minute period per hour	6-minutes
PM	0.14 lb/MWh or 0.015 lb/MMBtu or (0.03 lb/MMBtu and 99.9% reduction)	3-hour
SO ₂	0.8 lb/ MMBtu, 90% reduction or 0.20 lb/MMBtu, 0% reduction	30-day rolling
NO _x	0.50 lb/ MMBtu, 25% reduction	30-day rolling
Hg	20 x 10 ⁻⁶ lb/MWh or 0.020 lb/GWh	12-month rolling

On February 27, 2006, U.S. EPA revised 40 CFR Part 60, Subpart Da to reduce allowable emissions of NO_x, SO₂ and PM; and added a new Hg emission limits; for all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 MMBtu/hour for which construction is commenced after February 28, 2005. (70 FR 9866, February 28, 2006). The final version clarifies that heat recovery steam generators that are associated with stationary combustion turbines burning fuels containing 50 percent or more synthetic-coal gas are subject to Subpart Da and are not subject to 40 CFR Part 60, Subpart KKKK. Therefore, Subpart Da applies to Cash Creek. Any emission limits derived from the BACT analysis will be reconciled with Subpart Da emission limits.

40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (incorporated by reference in 401 KAR 60:005 Section 3(l))

The requirements of 40 CFR Part 60 Subpart GG ("Subpart GG") apply to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired. Subpart GG includes an SO₂ emission limit of 0.015 percent SO₂ by volume @ 15% O₂ on a dry basis (150 ppmvd @15% O₂) and a NO_x requirement that is applicable to units with heat inputs greater than 100 MMBtu/hr. The NO_x requirement is in the form of an emission limit equal to 75 ppmvd @ 15% O₂ based on the following formula:

$$E = 0.0075 \times \left(\frac{14.4}{Y} \right) + F$$

E = allowable NO_x percent emissions at 15% O₂ on a dry basis

Y = heat rate at max load (kJ/Whr) but less than 14.4kJ/Whr

F = NO_x emission allowance for fuel bound nitrogen

Since the total heat input to the combustion turbines at Cash Creek is greater than 100 MMBtu/hr both the SO₂ and the NO_x requirements of subpart GG apply to Cash Creek. However, Cash Creek must comply with significantly more stringent BACT emission limits for SO₂ and NO_x which also demonstrate compliance with Subpart GG.

40 CFR 60, Subpart JJJJ, National Emission Standards for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (Spark Ignition Internal Combustion Engines (SI ICE));

The applicant did not include this in the application. However, the Division has determined that it is applicable to the Emergency Fire Pump. On June 12, 2006, U.S. EPA proposed in the Federal Register (71 FR 33804, June 12, 2006) revised NO_x, CO and NMHC emission limits under 40 CFR Part 60, Subpart JJJJ, for all new, modified, or reconstructed stationary Spark Ignition Internal Combustion Engines. This addresses emissions from new, modified and reconstructed stationary Spark Ignition Internal Combustion Engines (SI ICE). These stationary engines are required to comply with the emission standards for nitrogen oxides (NO_x), carbon monoxide (CO) and non-methane hydrocarbons (NMHC). The Division has determined that the limits set by the proposed regulation are BACT for this emissions unit.

40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants, (incorporated by reference in 401 KAR 60:005 Section 3(ff))

40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants, incorporated by reference in 401 KAR 60:005, requires certain coal processing facilities to comply with certain particulate standards. Activities regulated by this NSPS include crushing, screening, conveying, and transferring of coal. Emission points are subject to an opacity limitation of 20 percent. . For point sources of these regulated activities enclosures, baghouses, vent filters and fogging that provide removal efficiencies in excess of 99% are selected as BACT.

40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, (incorporated by reference in 401 KAR 60:005 Section 3(1)(d))

40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, incorporated by reference in 401 KAR 60:005, apply to all steam generating units that commence construction, modification or reconstruction after June 19, 1984, and that have a heat input capacity greater than 29 MW (100 MMBtu/hr). This NSPS requires that SO₂ and NO_x emissions not exceed 0.20 lb/ MMBtu on a 30 day rolling average and emissions of particulate matter not be in excess of 0.030 lb/MMBtu. Proper boiler design, operation and maintenance, low NO_x burners using natural gas as fuel, with an operational limit of less than 500 hours provide BACT for the Auxillary Boiler.

3.3 Maximum Achievable Control Technology Standards (MACT)

40 CFR Part 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act

HAP emissions from Cash Creek will be less than 25 tons per year of combined HAP's and 10 tons per year for any single HAP. Therefore, Cash Creek is not a major source of HAPs.

40 CFR Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

On April 7, 2004, EPA proposed staying the effectiveness for two types of stationary combustion turbines, lean premix gas-fired turbines and diffusion flame gas-fired turbines, pending the outcome of EPA's proposal to delete these subcategories from the source category list (68 FR 18338, April 7, 2004). Cash Creek's turbines are diffusion flame gas-fired turbines. Under this stay, new sources in the two categories are temporarily relieved of the obligation to apply pollution controls and to comply with associated operating, monitoring, and reporting requirements. However, such sources must continue to submit Initial Notifications pursuant to 40 CFR 63.6145. If the subcategories are not ultimately delisted, the stay will be lifted, and all sources in the subcategories constructed or reconstructed after January 14, 2003 will then be subject to the final standards.

40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants, Industrial, Commercial, and Institutional Boilers and Process Heaters.

As Cash Creek is not a major source of HAP emissions, this regulation is not applicable. This Boiler MACT has been vacated by the Courts. However, since Cash Creek is not a major source of HAPs, there is no CAA Section 112(j) responsibility resulting from the vacature of the regulation..

3.4 Compliance Assurance Monitoring (CAM)

40 CFR Part 64

The U. S. EPA promulgated CAM regulations on October 22, 1997 as 40 CFR Part 64. The regulations require that new major sources (defined in CAM regulations as those whose potential criteria pollutant emissions prior to a control device exceed 100 tons/yr) must have a monitoring plan for each such pollutant. The proposed Cash Creek facility will have pre controlled emissions of NO_x in excess of 100 tons per year; therefore, CAM does apply to Cash Creek. Since Kentucky has a combined permitting program, the Title V operating permit must be issued with the Prevention of Significant Deterioration (PSD) construction permit. In accordance with 40 CFR 64.5, Compliance Assurance Monitoring requirements have been included in the permit for NO_x emissions from the combustion turbines. The use of the NO_x continuous emissions monitors will ensure compliance with NO_x CAM requirements.

3.5 Phase II Acid Rain Permits

Cash Creek applied for an Acid Rain permit with this PSD application (see Appendix B) to meet the Phase II Acid Rain requirements. Additionally, Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. Part 75 requires continuous emission monitoring for NO_x and SO₂.

3.6 Title V Operating Permit

As Cash Creek will emit greater than 100 tons per year of several pollutants it is subject to Title V permitting requirements of 401 KAR 52:020. As Kentucky's program is a combined permitting program, PSD construction requirements and Title V operating requirements are included in the initial permit.

3.7 State Regulations

Applicable State air quality regulations are summarized as follows.

401 KAR 51:210, CAIR NO_x Annual Trading Program

401 KAR 51:210 requires affected units to acquire NO_x emission allowances equal to their annual NO_x emissions. Cash Creek will acquire allowances necessary to meet compliance requirements of all applicable state and federal NO_x trading programs.

401 KAR 51:220, CAIR NO_x Ozone Season Trading Program

401 KAR 51:220 requires the control of nitrogen oxides (NO_x) emissions from large boilers and turbines used in power plants pursuant to the federal mandate published under the Clean Air Interstate Rule (CAIR), 40 C.F.R. 96.301 to 96.388. Cash Creek combustion turbines are defined as CAIR NO_x Ozone Season units since they are subject to 40 CFR 96.304.

401 KAR 59:016. New electric utility steam generating units(State-only).

For an electric utility combined cycle gas turbine, the affected facility is that part of the system that is the steam generating unit and the standards parallel the Federal NSPS standards. Cash Creek will be in compliance with Kentucky standards when it is in compliance with Federal NSPS standards. The emission and operating limits proposed as BACT are more stringent than Kentucky or Federal standards.

401 KAR 63:015, Flares

Emissions into open air of PM from any flare shall be no greater than 20% opacity for more than three (3) minutes in any one (1) day. Compliance will be accomplished by performing a qualitative visual observation of the opacity of emissions from the flare on a weekly basis and during the occurrence of any syngas flaring and maintain a log of the observations. If visible emissions determined by Reference Method 9 from the flare exceed the standard initiate an inspection of the flare and the entire process and make any necessary repairs.

401 KAR 63:010, Fugitive Emissions

Requirements apply to fugitive dust emissions from roads, material handling and storage operations. The regulation requires the owner or operator to utilize reasonable precautions to prevent particulate matter from becoming airborne and prohibits visible fugitive dust at the property line.

401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances

The regulation applies to certain facilities that emit potentially hazardous matter or toxic substances that are not elsewhere subject to State regulations. Cash Creek has potential emissions that require additional impact analysis as part of PSD analysis and this analysis was expanded to address this regulation. The analysis results are in Section 8 of the application.

401 KAR 50:042, Good Engineering Practice Stack Height

Table 3 - Cash Creek Stack Heights vs. GEP Stack Heights

The regulation applies such that a source may use it in establishing its applicable State Implementation Plan (SIP) emission limitation. A dispersion model accounting for aerodynamic plume downwash was used in the air quality impact assessment to determine GEP for Cash Creek stacks. The building structures were input directly into the AEROMOD model and the Building Profile Input Program (BPIP) routine calculated the downwash parameters. Table 3-5 of the application lists the modeled stack heights and results of the BPIP model showing the corresponding GEP stack heights. The complete BPIP model inputs and outputs are contained in Appendix K of the application.

Stack ID	Stack Description	Actual Stack Height (meters)	GEP Stack Height (meters)
AUXB	Auxiliary Boiler	18.29	65
HRSG1	HRSG 1 Stack	60.66	65
HRSG2	HRSG 2 Stack	60.66	65
TO30	Thermal Oxidizer	59.44	65
THDC33	Transfer House #1 Dust Collector	6.1	76.2
THDC34	Transfer House #2 Dust Collector	6.1	76.2
CRDC35	Coal Reclaim Dust Collector	6.1	76.2
FLARE	Flare	61.81	65
CT1-CT10	Cooling Tower Cells 1-10	15.24	65
FP	Fire Pump	12.19	65
K3	Barge Unload Belt to Hopper	6.1	76.2

3.8 Non-Applicable Regulations

40 CFR Part 60, Subpart J Standards of Performance for Petroleum Refineries (incorporated by reference in 401 KAR 60:005 Section 3(1)(n))

While 40 CFR Part 60, Subpart J contains standards for Claus Plants, it is limited to only those Claus units that are located or co-located with Petroleum Refineries and not IGCC units. The BACT analysis and permit terms were written with the view of this standard's monitoring and recordkeeping techniques.

401 KAR 60:020 Mercury Budget Trading Program. Promulgated to meet the requirements of 40 CFR 60 Subpart HHHH Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units

The Commonwealth is currently in the process of adopting a regulation that will fulfill the requirements of 40 CFR 60 Subpart HHHH. Cash Creek is expected to be required to obtain mercury emission credits for either existing sources or purchase them from the Commonwealth's new source "pool".

4. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

Pursuant to 401 KAR 51:017, a major stationary source subject to a PSD review shall meet the following requirements:

- (a) The proposed source shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.
- (b) The proposed source shall meet each applicable emissions limitation under Title 401 KAR 50 to 65, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

Table 4-1 Emissions Increase vs. Significant Levels

POLLUTANT	POTENTIAL EMISSIONS INCREASE FROM THE PROPOSED FACILITY (TONS/YEAR)	SIGNIFICANT NET EMISSIONS LEVEL (TONS/YEAR)
Total Particulate	415	25
PM₁₀	168	15
SO₂	391	40
H₂SO₄	67	7
NO_x	704	40
CO	965	100
VOC	32	40
Pb	.02	0.6

The following pollutants are subject to BACT: particulate matter (PM), (PM₁₀ and PM_{2.5}), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), and sulfuric acid mist (H₂SO₄). However, , until EPA promulgates the PM_{2.5} NSR implementation rules, PM₁₀ in accordance with EPA's current guidance will serve as a surrogate for PM_{2.5}. Also, a BACT review is not required for VOC because the predicted emissions are below 40 tons per year.

4.1 BACT Overview

Cash Creek submitted a top-down Best Available Control Technology (BACT) analysis following the U.S. EPA guidance, "New Source Review Workshop Manual" (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

- 1. Identify all control technologies
- 2. Eliminate technically infeasible options
- 3. Rank remaining control technologies by control effectiveness
- 4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results
- 5. Select BACT.

4.2 Step 1 - Identify All Control Technologies

Using the top-down approach, Cash Creek selected various technologies for analysis of technical and practical feasibility, and then applied economic cost-effectiveness analyses where the top ranked technology was not selected.

4.2.1 Generating Technology Analysis and Selection

Cash Creek considered three electricity-generating technologies in their design evaluation which included: Pulverized Coal (PC), Circulating Fluidized Bed (CFB) combustion and Integrated Gasification Combined Cycle (IGCC).

PCs and CFBs emission reductions are accomplished with post-combustion emission control technologies (such as SCR, SNCR, FGD and FF), whereas, IGCC emissions are controlled before or during combustion. In an IGCC plant, particulate matter, mercury, SO₂, and H₂SO₄, emissions are controlled by cleaning the syngas. CO and VOC emissions are minimized by proper process design and use of combustion controls. For an IGCC plant, the particulate removal process will reduce emissions by more than 99.9% and acid gas/sulfur recovery systems will reduce potential SO₂ emissions by more than 99%. NO_x is minimized through nitrogen injection prior to combustion of syngas in the combustion turbines, and by Selective Catalytic Reduction post combustion. A comparison is shown below of typical permitted limits.

Table 4-2 Comparison of PC, CFB, and IGCC Emission Rates

Pollutant	PC lb/MMBtu	CFB lb/MMBtu	IGCC lb/MMBtu
PM ₁₀ *	0.015	0.012	0.009
SO ₂	0.187	0.150	0.033
NO _x	0.050	0.070	0.059
CO	0.150	0.150	0.040
VOC	0.005	0.004	0.003
H ₂ SO ₄	0.005	0.005	0.004

*based on filterable particulate emissions

The proposed emission rates are listed in Table 4-6 of the application and below.

Table 4-3 Proposed Emission Rates

Pollutant	Emission Rate Gasifier Heat Input (lbs/MMBtu)	Emission Rate C T Heat Input (lbs/MMBtu)	Control Technology
NO _x	0.0246	0.0331	Nitrogen injection and SCR
SO ₂	0.0117	0.0158	AGR syngas cleanup
PM _{10-Filterable}	0.0063	0.0085	syngas cleanup
PM _{10-Total}	0.0161	0.0217	
CO	0.036	0.0485	combustion controls
VOC	0.0017	0.0015	combustion controls
H ₂ SO ₄	0.0026	0.0035	AGR syngas cleanup

4.2.2 Fuel selection

Cash Creek's CTs are designed to use syngas derived from bituminous coal with natural gas as the secondary and start-up fuel.

Cash Creek considered and dismissed coal washing as an ancillary emission control measure due to detrimental impacts on the gasification process. Cash Creek indicated that:

- Reduction of ash entering the gasification process could require the addition of fluxant material (such as sand) to facilitate the gasification and slag removal process.
- An attempt to over-scrub lower sulfur content fuels in the AGR would produce detrimental results. Over scrubbing results in additional CO₂ capture, which acts as a diluent in the Sulfur Recovery Unit and stresses

the Tail Gas Treatment Unit, resulting in increased emissions of SO₂ from the thermal oxidizer.

- The particulate washing process associated with the IGCC system achieves the same average removal efficiency regardless of ash content.

The Division concurs that coal washing should not be required.

4.2.3 Control Technology Options

To determine available technologies Cash Creek considered several sources including: EPA's RACT/BACT/LAER Clearinghouse and Control Technology Center (RBLC); recent submitted PSD applications; recently issued or proposed permits; and information from control technology vendors and engineering/environmental consultants. These control technologies are identified for each applicable pollutant are listed below.

Table 4-4 Possible Control Strategies & Technologies

POLLUTANT	COMBUSTION CONTROL TECHNOLOGIES	MATERIAL HANDLING CONTROL TECHNOLOGIES	COOLING TOWERS	FUGITIVE
PM/PM ₁₀	<u>Pre-Combustion</u> IGCC Syngas Scrubbing <u>Post-Combustion</u> Baghouse Electrostatic Precipitator ("ESP") Wet ESP ("WESP") Scrubbers Cyclone	Enclosures Baghouse Fogging	Drift Eliminators	Suppressants Compaction Telescopic Chutes
SO ₂ H ₂ SO ₄	<u>Pre-Combustion</u> IGCC Acid Gas Removal Coal Washing <u>Post-Combustion</u> Wet Flue Gas Desulfurization(WFGD) Dry Sorbent Injection ("DSI") Dry Scrubbers	N/A	N/A	N/A
NO _x	<u>Pre-Combustion</u> Diluent Injection Dry Low NO _x Burners <u>Post-Combustion</u> Selective Catalytic Reduction ("SCR") Selective Non-Catalytic Reduction ("SNCR")	N/A	N/A	N/A
CO	<u>Pre-Combustion</u> Excess Air Proper Design and Operation <u>Post-Combustion</u> Thermal Oxidation Catalytic Incineration	N/A	N/A	N/A

4.3 Step 2 - Technical Feasibility Analysis

The control technologies for PM/PM₁₀, SO₂, NO_x, CO, VOC and H₂SO₄ were then evaluated for technical feasibility and applicability. Cash Creek determined that Thermal Oxidation (TO) [except for its use in the Acid Gas Removal process], Catalytic Incineration (CI), dry Low NO_x Burners (LNB), and SCONOX to be infeasible because they are not available and/or not applicable. findings are as follows:

Thermal Oxidation (TO) - As a control device for CO, Thermal Oxidation is not listed in the RBLIC database for any proposed or permitted electric generating process, including IGCC. Therefore, Cash Creek determined that Thermal Oxidation is not available or applicable.

Catalytic Incineration (CI) - As a control device for CO, catalytic incineration is not listed in the RBLIC database, EPA literature for utility boiler air emissions control, or any proposed or permitted electric generating process, including IGCC. Therefore, Cash Creek determined that Thermal Oxidation is not available or applicable.

Low NO_x Burners (LNB) - One method to reduce thermal NO_x is to use LNB. However, Cash Creek rejected this option since hydrogen is a major constituent of synthesis gas and hydrogen's high flammability and flame speed can initiate flashback and combustor failure. Also, there are no commercially available LNBs for IGCCs firing syngas. Therefore, Cash Creek determined that LNBs are not available or applicable for IGCC units firing syngas. Since LNB's were rejected as being unfeasible due to usage of syngas and not natural gas, the permit has been a condition to limits the amount and duration of natural gas combustion.

4.4 Step 3 - Ranking of the Remaining Control Technologies

After eliminating the technically infeasible control alternatives, Cash Creek reviewed and ranked each control technology for effectiveness.

First, Cash Creek identified the following control technologies as having the most stringent emission limits for non-IGCC coal-fired units:

Table 4-5 Summary of Control Technologies

POLLUTANT	SOURCE	MOST STRINGENT EMISSION LIMIT	CONTROL TECHNOLOGY
PM/PM ₁₀ PM _{2.5}	Boilers	0.012 lb/MMBtu (filterable) 0.018 lb/MMBtu (total)	Baghouse or Electrostatic Precipitator
	Materials Processing	99+% control	Baghouse Enclosures
	Cooling Towers	99.9995% control	Mist (Drift) Eliminators
	Fugitives	20% Opacity	Suppressants, Compaction Telescopic Chutes
SO ₂	Boilers	0.08 lb/MMBtu	WFGD/Western US coal
NO _x	Boilers	0.05 lb/MMBtu	Boiler Design and Operation/ Low NO _x Burners/ SCR
CO	Boilers	0.085 lb/MMBtu	Boiler Design & Operation
H ₂ SO ₄	Boilers	0.004 lb/MMBtu	WESP and WFGD

As IGCC is a new technology for electric generation, Cash Creek was only able to identify 8 sources available for comparison. The most stringent emission limits for

existing and proposed IGCC units are listed below:

Table 4-6 Summary of Most Stringent Limits for Existing and Proposed IGCC Sources

Pollutant	Source	Most Stringent Emission Limit
PM/PM ₁₀	Wabash SICEC	0.005 lb/MMBtu (filterable) not met 0.009 lb/MMBtu
SO ₂	Lima	0.02 lb/MMBtu
NO _x	SICEC	0.059 lb/MMBtu
CO	Elm Road	0.03 lb/MMBtu
VOCs	Elm Road	0.002 lb/MMBtu
H ₂ SO ₄	Elm Road	0.00005 lb/MMBtu

Using the emission information of the two previous tables, control technologies were ranked in order of decreasing effectiveness, as follows:

Table 4-7 Ranking of Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Add-On Control Efficiency (%)*
PM/PM ₁₀ Combustion Turbine	IGCC Syngas Scrubbing	99+
	Baghouse or ESP/WESP	99+
	Scrubber	99+
	Cyclone	90+
PM/PM ₁₀ Material Handling	Baghouse	99+
	Enclosures with Vent Filters	99+
PM/PM ₁₀ Cooling Towers	Fogging	99+
	0.0005% Drift Eliminators	90+
PM/PM ₁₀ Fugitives	Suppressants	80-90
	Compaction	80-90
	Telescopic Chutes	80-90
SO ₂	IGCC AGR	99+
	WFGD	98+
	Dry Scrubber	80-90
	Coal Washing	30-35
NO _x	SCR	60-90
	Diluent Injection	40-75
	SNCR	40-70
	Proper Design and Operation	Varies
CO	Proper Design and Operation	Varies
H ₂ SO ₄	IGCC AGR	99+
	DSI/Baghouse/WFGD	99+
	WESP	98+
VOCs	Proper Design and Operation	Varies

Cash Creek noted that, in some instances, reaching those limits for one pollutant may prohibit attaining the most stringent limit for another. For example combustion processes reducing NO_x to the lowest level may significantly increase CO or H₂SO₄ emissions.

4.5 Step 4 - Top Down Evaluation of Control Options

4.5.1 Particulate Matter

There are four sources of particulate matter from Cash Creek: combustion turbines, material handling units, cooling tower and fugitive sources.

4.5.1.1 Particulate Matter (PM₁₀ and PM_{2.5}) (IGCC)

Although PM_{2.5} is a regulated NSR pollutant and there is a National Ambient Air Quality Standard (NAAQS) for PM_{2.5}, which became effective on September 16, 1997; as discussed in the Memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, Interim Implementation of New Source Review for PM_{2.5} (Oct. 23, 1997); until U.S. EPA promulgates the PM_{2.5} major NSR regulations, States and local air pollution control agencies should use PM₁₀ as a surrogate for PM_{2.5}. On March 29, 2007, EPA issued the Clean Air Fine Particle Implementation Rule, which has begun to define requirements for State Implementation Plans to address improving PM_{2.5} nonattainment areas. However, this rule specifically does not address requirements for NSR requirements for PM_{2.5}. These requirements will be addressed in separate rulemaking. Therefore, at this time the BACT analysis for PM₁₀ shall be a surrogate for PM_{2.5}.

In a typical combustion process, particulate matter is removed by post-combustion processes such as fabric filters or electrostatic precipitators. However, in an IGCC plant, particulate matter could damage the turbine(s), so it is necessary to use pre-combustion controls. Therefore, particulate removal is an integral part of the gasification process. Heavier mineral and ash matter, referred to as coarse slag, is not entrained in the syngas and is captured in the gasifier. As noted in Section 1.4, prior to leaving the gasifier, syngas passes over a water pool located at the bottom of the unit which enhances collection of the slag.

Fine slag is composed of mineral compounds and fuel particles that are not completely gasified (unburned carbon). This material is carried from the gasifier and is removed by scrubbing with water to remove entrained particulates.

These processes are approximately 99.9% efficient at removing particulate matter, and result in an emission limit for PM/PM₁₀ (filterable) of 0.0063 lb/MMBtu based on a 3 hour average while firing natural gas and 0.0085 lb/MMBtu while firing synthesis gas. This limit is more stringent than the PM₁₀ limit achieved at current operating IGCC units.

Cash Creek noted that sulfuric acid mist is the most widely recognized form of condensable PM emitted by combustion sources. Other inorganic species that can contribute to condensable PM emissions include ammonium bisulfate, other acid gases such as HCL, HF and trace volatile metals. Because sulfuric acid mist is the main constituent of inorganic condensable PM, and because control technologies that remove sulfuric acid mist are also effective in removing other acid gases, Cash Creek indicated that the control of sulfuric acid mist serves as an effective proxy for the control of condensable PM. Furthermore, control devices applicable to SO₂ emissions reductions in an IGCC are the same that are applicable to control H₂SO₄. Therefore, Cash Creek concluded that a single analysis is required to determine BACT for SO₂, H₂SO₄, and condensable PM.

After considering similar sources and the proposed IGCC technology, it was determined that both filterable PM/PM₁₀ and total PM/PM₁₀ emission limits for synthesis fuel and natural gas firing would be necessary for the proposed facility. A filterable PM/PM₁₀ emission limit of 0.0063 lb/MMBtu based on the heat input to the gasifiers (0.0085 lb/MMBtu based on the heat input to the combustion turbines) represents BACT for Cash Creek when firing synthesis gas. Similarly, a filterable PM/PM₁₀ emission limit equal to 0.0063 lb/MMBtu based on the heat input to the combustion turbines represents BACT when

firing natural gas. It was also determined that a PM/PM₁₀ limit would be required as demonstration of BACT for the proposed facility. PM/PM₁₀ consists of both filterable (e. g., ash, metals, etc.) and condensable (e. g., H₂SO₄, Hg, etc.) particulates. Based on this information a PM/PM₁₀ emission limit was determined to consist of the filterable PM/PM₁₀ emissions limit added to the condensable emissions (including the H₂SO₄ emission limit discussed in Section 4.6.7 of the supplemental application). A PM/PM₁₀ emission limit of 0.0161 lb/MMBtu based on heat input to the gasifiers (0.0217 lb/MMBtu based on heat input to the combustion turbines) was determined to represent BACT when firing synthesis gas. A PM/PM₁₀ emission limit of 0.0107 lb/MMBtu based on heat input to the combustion turbine was determined to represent BACT when firing natural gas. Each of these emission limitations are more stringent than the PM₁₀ emission limit achieved in practice at currently operating IGCC units and the lowest proposed PM₁₀ emission limit for any proposed coal-fired unit.

4.5.1.2 Particulate Matter (Material Handling)

Cash Creek has selected baghouses, vent filters and fogging as BACT for PM/PM₁₀ emission controls for material handling facilities for coal and slag. Use of these emission controls is expected to result in a removal efficiency of approximately 99.5%, and therefore represents BACT. Fogging will be used in instances where it provides controls equal to or better than baghouse or filter. The Division concurs that these measures are BACT. It was determined based on the application and unit design that PM/PM₁₀ total limit consisting of both filterable (i.e ash, metals, etc) and condensable emissions (including H₂SO₄, Hg) particles shall be used as the demonstration of BACT for the facility.

4.5.1.3 Particulate Matter (Cooling Towers)

The highest control efficiency to reduce the amount of drift (PM₁₀ emissions) from cooling towers involves the instillation of drift eliminators. These are designed to remove as many droplets of particulate as feasible before leaving the cooling towers, thus minimizing PM emissions and conserving water usage by the cooling towers. Cash Creek has selected 0.0005% drift eliminators as BACT for particulate control on the cooling towers.

4.5.1.4 Particulate Matter (Fugitives)

Fugitive emissions originate at active and inactive areas of storage piles, roads, and loading and unloading operations. Cash Creek proposes to use suppressants (both water and chemical); compaction; and telescopic chutes, stacking tubes, and reduced drop heights to reduce fugitive emissions. Inactive long-term storage piles will be compacted and suppressed as needed. When storage piles are active or if erosion causes emissions, suppressants will be used to control fugitive emissions. Drop heights will be optimized to reduce emissions while allowing for proper operation. Chutes or stacker tubes will be used when loading coal to the storage pile. Permanent roads and parking lots will be paved. These technologies represent the highest control levels for fugitive particulate emissions from the facility.

4.5.2 Sulfur Dioxide and Sulfuric Acid Mist (IGCC)

In this IGCC design, the acid gas removal unit extracts H₂S and COS from the synthesis gas. Either Selexol or Rectisol can be used in the acid gas removal unit. Based on economic considerations and the insignificance of the removal efficiency difference between Selexol and Rectisol, the Division

concurs with Cash Creek that Selexol is the correct choice for BACT in the acid gas removal unit for the synthesis gas going to the combustion turbines.

Use of Selexol determines the amount of sulfur contained in the gases that proceed from the acid gas removal unit to the sulfur recovery system. The sulfur recovery system consists of the two Claus stages, the thermal oxidizer and the flare. The amount of sulfur in the gases that go to the sulfur recovery system is minimally impacted by the 99.8% removed by Selexol or the 99.9% that might be removed by Rectisol (a difference of only two pounds per ton of sulfur removed); it is not a significant factor in emissions from the sulfur recovery unit. The emission limit on the Claus stages is the only significant factor determining emissions of sulfur from the sulfur recovery unit.

The Division did an extensive review of permitted sulfur recovery units for refineries, natural gas treatment processes, and coal gasification systems. Based on the Division's research, an exhaust stream from the sulfur recovery system containing 100 ppm sulfur is the best permitted emission rate and the best emission rate demonstrated in practice by any type of sulfur recovery unit. The Division set the BACT limit for sulfur from the sulfur recovery unit at 100 ppm. This is lower than any other permitted IGCC unit and is significantly lower than the proposed standard of performance for petroleum refineries which allows an emission limit of 250 ppm (72 Federal Register 27178, Monday, May 14, 2007).

The applicant did not propose an emission limit from the sulfur recovery unit but instead proposed an hourly emission rate of 20.82 lbs/hr, which equates to an annual emission rate of 91.2 tpy of sulfur dioxide. The Division calculated the annual emission rate of sulfur dioxide based on the 100 ppm emission limit, and determined that it would be less than the proposed emission rate of 91.2 tpy of sulfur dioxide. The Division did not accept the 91.2 tpy sulfur dioxide emission estimate included in the Statement of Basis in Table 2-1 as a BACT limit, nor is it included in the permit as such. Instead, the Division imposed the 100 ppm limit contained in the permit as BACT.

Both SO₂ and H₂SO₄ emissions from an IGCC combustion turbine are produced in relationship to the concentrations of sulfur constituents in the syngas. Possible control devices for reducing SO₂ and H₂SO₄ emissions include both post-combustion and pre-combustion devices. Post-combustion Wet Flue Gas Desulfurization (WFGD) alone or combined with other controls (such as Wet Electrostatic Precipitators) has been the preferred method for SO₂ and inorganic condensable emissions (H₂SO₄) reduction and BACT compliance for high sulfur fossil-fueled combustion sources. However, in an IGCC, the syngas is treated prior to combustion, which is necessary to avoid damage to the turbine from acid gas and particulates and generally results in greater removal efficiencies. The table below summarizes the data used by Cash Creek in its BACT analysis.

Table 4-8 SO₂ and H₂SO₄ Emission Control Options

Pollutants	Control Technology	Potential Control (%)
SO ₂	<u>Pre-Combustion</u>	
	Physical Absorption	99.5+
	Chemical Absorption	99.4+
	Coal Washing	30-35
	<u>Post Combustion</u>	
	WFGD	98+
	Dry Scrubber	80-90

Since the highest available removal efficiencies are associated with pre-combustion controls, Cash Creek did not consider post-combustion controls in its BACT analysis.

Cash Creek noted that the gasification process involves conversion of a coal slurry and oxygen at very high temperature and pressure into a CO and H₂ rich fuel. By products that result from using high sulfur coal as a feedstock are the gaseous pollutants H₂S and COS. These pollutants are removed in a pre-combustion Acid Gas Removal System ("AGR"), which is very effective in removing the H₂S but does not readily remove COS. To address this removal problem the COS is mixed with water in a hydrolysis reactor which produces H₂S and CO₂. The syngas is then cooled and sent to the AGR for cleaning. The AGR is essentially a scrubbing operation that can be performed by chemical or physical absorption. There are currently two physical absorption solvents, *Selexol*[™] and *Rectisol*[™], and one chemical absorption solvent, MDEA, available for use at Cash Creek.

Physical Absorption

Physical absorption methods, including *Selexol*[™] and *Rectisol*[™], use solvents that dissolve acid gases under pressure. Solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Thus, increased operating pressure in an absorption column facilitates separation and removal of an acid gas like H₂S. The dissolved acid gas can then be removed from the solvent, which is regenerated, by depressurization in a stripper.

Union Carbide's *Selexol*[™] solvent made of dimethyl ether or polyethylene glycol has been used successfully in chemical facilities to treat process gas streams. Feed gas is cooled with water and then flows to an absorption tower where it is introduced to the *Selexol*[™] solvent in a countercurrent flow. Acid gases in the feed gas are absorbed into the solvent, and a clean feed gas is withdrawn from the top of the absorber column. Acid gas rich solvent from the absorber is regenerated by flashing it to medium pressure, then reheating the gas to the solvent boiling point and stripping the solvent. Based on GE information, and engineering judgment, the *Selexol*[™] process removes 99.8% of the sulfur contained in the syngas.

Rectisol[™], also a physical absorption process, uses cold methanol as the physical solvent. Sour syngas entering the AGR is cooled, and trace chemical components are removed with a cold methanol pre-wash. Then, H₂S is physically absorbed from the raw gas using CO₂-rich methanol. Raw gas is removed from the top of the absorption column, with clean syngas removed from a lower point in the column. The solvent is reclaimed through pressure reduction, stripping, and re-boiling. Although *Rectisol*[™] has not been used in an AGR serving an IGCC facility, there are no known technical limitations that would render the process technically infeasible for the AGR system. Based on information from GE, and engineering judgment, the *Rectisol*[™] process removes 99.9% of the sulfur contained in the syngas.

Chemical Absorption

In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. The amine solvent considered for chemical absorption is methyldiethanolamine ("MDEA"). Amine solvents, such as MDEA, react forming a chemical bond between the acid gas and the solvent in an

absorption tower. Solvent is reclaimed by a heating process in a stripper tower producing regenerated MDEA and a concentrated H₂S stream that is directed to the sulfur recovery process. The sulfur recovery process removes the sulfur and treats the tail gas by thermal oxidation.

Chemical absorption, successfully used at existing IGCC facilities to reduce the sulfur content of syngas, is a feasible technical option to serve Cash Creek. Based on information from GE, and engineering judgment, Cash Creek concluded that the MDEA process could remove 99.4% of the sulfur contained in the syngas.

BACT Selection for SO₂

The most effective SO₂ control systems that are technically feasible for the proposed facility are physical absorption AGR systems, using Selexol™ or Rectisol™ solvents. Both are capable of removing over 99% of the sulfur from the syngas based on feasibility studies performed by vendors with Selexol achieving 0.0117 lb/MMBtu removal and Rectisol possibly reaching 0.00585 lb/MMBtu removal. Cash Creek has selected the Selexol™ system to reduce SO₂ and acid gases emissions. Since Rectisol™ has the potential to more effectively reduce SO₂ emissions and acid gases, Cash Creek felt that a BACT analysis requires an evaluation of the economic, energy and environmental impacts associated with the both the Selexol™ system and the Rectisol™ systems. However, Cash Creek noted that no IGCC facilities operate with either a Selexol™ or Rectisol™ AGR system; so accurate costs associated with these technologies are based on vendor discussions, trade show presentations, similarly proposed sources, or discussions with non-utility gasification sources.

Economic Evaluation

In its economic evaluation, Cash Creek analyzed both average and incremental cost effectiveness.

Because of the potential for damage to the turbine, Cash Creek did not feel it was realistic to use a completely uncontrolled number as a baseline to use in calculating "average cost effectiveness", which is typically expressed as annual costs of removal divided by tons of pollutant removed. Instead, Cash Creek used what it felt was a more realistic baseline by using emissions from the Wabash River IGCC unit and a theoretical analysis using MDEA to control SO₂. The Wabash River represents actual operating experience while MDEA represents the minimum control feasible. The following tables are the numbers used in Cash Creek's analysis.

Table 4-9 Average Cost Effectiveness Using the Uncontrolled Baseline Rate

CONTROL TECHNOLOGY	SO ₂ EMISSIONS (LB/MMBTU)	ANNUAL EMISSIONS (TONS)	INCREASE IN ANNUAL COST (\$)	ANNUAL AVERAGE COST (\$/TON)
Rectisol™	0.00585	149	19,797,825	94
Selexol™	0.0117	299	16,070,591	77
Uncontrolled	8.22	210,044	Baseline	Baseline

Table 4-10 Average Cost Effectiveness Using the Wabash Baseline Rate

CONTROL TECHNOLOGY	SO ₂ EMISSIONS (LB/MMBTU)	ANNUAL EMISSIONS (TONS)	INCREASE IN ANNUAL COST (\$)	ANNUAL AVERAGE COST (\$/TON)
<i>Rectisol</i> TM	0.00585	149	19,797,825	5,126
<i>Selexol</i> TM	0.0117	299	16,070,591	4,328
Wabash	0.157	4,012	Baseline	Baseline

Table 4-11 Average Cost Effectiveness Using the MDEA Baseline Rate

CONTROL TECHNOLOGY	SO ₂ EMISSIONS (LB/MMBTU)	ANNUAL EMISSIONS (TONS)	INCREASE IN ANNUAL COST (\$)	ANNUAL AVERAGE COST (\$/TON)
<i>Rectisol</i> TM	0.00585	149	19,797,825	20,524
<i>Selexol</i> TM	0.0117	299	16,070,591	19,715
MDEA	0.0436	1,114	Baseline	Base

Energy Evaluation

Although additional energy requirements are associated with each of the acid gas recovery processes, Cash Creek concluded that their energy consumption is nominal when compared with balance of plant auxiliary power needs and does not warrant dismissing any of these processes from consideration as BACT.

Environmental Evaluation

Each of the Acid Gas Removal (AGR) methods evaluated in this BACT analysis involves a chemical process that uses a solvent to remove H₂S from syngas. Clean syngas from the AGR will be used as fuel in the combustion turbines. Each solvent used in the AGR will be regenerated and reused. Acid gases removed from the syngas will be processed to generate elemental sulfur in a sulfur recovery system. In each case, the AGR will generate a wastewater stream that must be processed prior to discharge. Cash Creek concluded that there are no unique collateral environmental issues that would preclude use of any of these AGR systems for SO₂ control as BACT.

Conclusion

Although no environmental or energy impacts favor one solvent AGR process over the other, the costs associated with the *Rectisol*TM system are significantly more than those for the *Selexol*TM system as compared with added reductions of SO₂ emissions. The *Rectisol*TM system has initial capital cost of approximately \$93 million and annual operating cost of almost \$11 million. The *Selexol*TM system has initial capital cost of about \$73 million and annual operating cost near \$9 million. Also, considering the average and incremental cost effectiveness of the alternatives, the *Selexol*TM system is the most attractive and results in emission rates lower than those achieved in practice at any currently operating IGCC, CFB, or pulverized coal boiler processing bituminous coal. Based on this information the *Rectisol*TM process is determined to be cost prohibitive to represent BACT for the project. Cash Creek determined that the *Selexol*TM process in combination with an SO₂ emission limit of 0.0117 lb/MMBtu, based on a 3-hr rolling average and an H₂SO₄ limit of 0.0026 lb/MMBtu based on a 3-hr rolling average represents BACT for Cash Creek's IGCC combustion turbines when firing syngas or

natural gas. These emission limitations represent removal efficiencies greater than 99% and are greater than the efficiencies achieved in practice at currently operating IGCC units².

The Division concurs with the decision to use the *Selexo*TM process. Because no IGCC facility currently operates with either a *Selexo*TM or *Rectiso*TM system, no entity has long term operating experience and no historical data exists regarding actual operating costs. The margin of error introduced by this lack of experience renders the difference between vendor guarantees of removal efficiency and of operating costs to be negligible at this time. Therefore, the decision must be made based on the initial cost of the system.

4.5.3 Oxides of Nitrogen (IGCC)

NO_x control methods may be divided into combustion controls and post-combustion controls. Combustion NO_x controls reduce the NO_x generated and post-combustion NO_x controls remove NO_x by treating exhaust gases. A number of control options were listed in the application as follows:

Table 4-12 NO_x Emission Control Options

Control Method	Control Add-on Efficiency
Selective Catalytic Reduction (SCR)	60-90%
Diluent Injection	40-75%
Steam Injection	40-75%
Selective Non-Catalytic Reduction (SNCR)	40-70%

NO_x BACT Selection

Cash Creek selected SCR and nitrogen diluent to control NO_x emissions from the source. This combination of control processes with a NO_x emission limit of 0.0246 lb/MMBtu, based on a 24-hr rolling average represents BACT for the Cash Creek IGCC combustion turbines when firing natural gas and 0.0331 lb/MMBtu during any rolling 24-hour average period (approximately 5 ppmvd @ 15 % oxygen (O₂)) when firing synthesis gas. These emission limitations represent a removal efficiency of approximately 90%. This is lower than the emission achieved in practice at currently operating IGCC units and the lowest proposed emission limits for proposed coal-fired units, including other proposed IGCC units.

4.5.4 Carbon Monoxide (IGCC)

Carbon monoxide, a product of incomplete combustion, often results from achieving lower NO_x emissions. As stated earlier, the best methods for CO control is thermal oxidation and catalytic incineration. However, Cash Creek has indicated that neither technology is feasible for its units, but noted that a properly designed and operated combustion turbine effectively functions as a thermal oxidizer. When the temperature and excess oxygen availability are adequate for complete combustion CO formation is minimized. Minimization of the CO emitted is in the economical best interest of the operator because CO represents unutilized energy exiting the process. This is especially true in

² It should be noted that the Orlando Utility Commission & Southern Power Company's IGCC project in Orlando, Florida has a draft permit emission limit of 35.5 lb/hr (approximately 0.015 lb SO₂/MMBtu). See "Addendum to Technical Evaluation and Preliminary Determination dated July 26, 2006", at <http://www.dep.state.fl.us/Air/permitting/construction/oucsouthern.htm>.

the case of IGCC since the primary energy component of syngas produced from gasification is CO.

CO emission rates are also identified as a potential factor that affects NO_x emissions on an inverse proportional basis (*i.e.*, lower CO tends to produce higher NO_x). Therefore any attempt to increase efficiency of the combustion turbines to reduce CO would potentially result in an increase in thermal NO_x emissions. Cash Creek concluded that based on the EPA's emphasis to reduce NO_x emissions, further reductions in CO emissions at the expense of increasing NO_x emissions are not warranted.

Carbon Monoxide BACT Selection

The applicant proposes proper operation and maintenance in combination with an emission limit of 0.036 lb/MMBtu based on a 24-hour rolling average when firing syngas and 0.0449 lb/MMBtu, based on a 24-hour rolling average when firing natural gas, to be BACT for Cash Creek combustion turbines. This is supported by recent permits and applications for coal fired and IGCC projects.

Auxiliary Equipment Emissions

In addition to the combustion turbines, material handling equipment, and cooling towers, Cash Creek will have an auxiliary boiler and firewater pumps that will operate for a limited period of time each year.

Auxiliary Boiler

The 278.8 MMBtu/hr auxiliary boiler will be used to generate steam for start-up of the gasifiers. The steam is used to purge the gasifiers, provide pre-heat to the gasifier radiant syngas cooling section, and maintain temperature and pressure.

To minimize pollutant emissions, the auxiliary boiler will have low NO_x burners and fire natural gas. The auxiliary boiler will be restricted in hours of operation to less than 500 hours per year. The applicant is proposing proper boiler design and operation, low NO_x burners and use of natural gas to be BACT for the auxiliary boiler. The BACT emissions limits for the auxiliary boiler are set out in Table 4-16. Also, other controls sometimes used on large natural gas-fired boilers - such as FGR, SCR, and SNCR - would be either technically or economically infeasible when considered in addition to the control methods that will be required.

Firewater Pumps

The proposed facility will be equipped with one electric and one natural gas-fired firewater pump for emergency fire protection. The natural gas fired pump will only be operated in case of an emergency and for short test periods.

The Applicant proposes to limit testing of the natural gas fire pump to less than 500 hours a year. This is similar to other sources in the Commonwealth of Kentucky. Therefore, the Applicant proposes limiting the hours of operation and use of natural gas to be BACT for the natural gas fire pump. BACT emissions limits for the natural gas fire pump are set out in Table 4-17. No emissions are expected from the electric fire pump.

Thermal Oxidizer And Flare

The proposed facility will use a flare for periods of startup, shutdown and malfunction. BACT may be no less stringent than a standard contained in 40 CFR 60 or 40 CFR 61. The Division has determined that upon review that BACT for PM and PM10 is compliance with the control requirements of 40 CFR 63.11. These are more stringent than the requirements in 40 CFR 60.18.

4.6 Step 5 - Select BACT

Tables 4-13 to 4-17 summarize the BACT determinations for Cash Creek's proposed IGCC combustion turbines, material handling, cooling towers, auxiliary boiler, and fire water pumps. All control technologies selected as BACT are supported by recent entries into the RBLC database, recently proposed applications, and/or other permits. In addition, the various air quality dispersion-modeling analyses performed for Cash Creek demonstrate that criteria pollutant impacts from increased emissions fall below all NAAQS and PSD regulatory limits.

Table 4-13 BACT Determination for the Combustion Turbines

Pollutant	Emission Limit Based On C T Heat Input	Averaging Time	Control Technology
Firing Syngas			
PM/PM ₁₀	0.0085 lb/MMBtu	3-hour	Syngas Scrubbing
Filterable PM/PM ₁₀	0.0217 lb/MMBtu		
Total SO ₂	0.0158 lb/MMBtu	3-hour	Acid Gas Removal by physical absorption with Selexol solvent
NO _x	0.0331 lb/MMBtu	24-hour	SCR and Diluent N ₂ Injection
CO	0.0485 lb/MMBtu	24-hour	Proper Combustion and Operation
H ₂ SO ₄	0.0035 lb/MMBtu	3-hour	Acid Gas Removal by physical absorption with Selexol solvent
Firing Natural Gas			
PM/PM ₁₀	0.0063 lb/MMBtu (filterable)	3-hour	Proper Combustion and Operation and Fuel Characteristics
SO ₂	0.00117 lb/MMBtu	3-hour	Proper Combustion and Operation and Fuel Characteristics
NO _x	0.0246 lb/MMBtu	24-hour	SCR and Diluent N ₂ Injection
CO	0.0449 lb/MMBtu	24-hour	Proper Combustion and Operation

Table 4-14 BACT Determination for Material Handling

Pollutant	Emission Source	Control Device
PM/PM ₁₀	Point Source	Enclosures Baghouses Vent Filters Fogging
	Fugitive Source Storage Pile and Operations	Compaction Suppressants Reduced Drop Heights Stacking Tubes
	Vehicles	Paved Roads Where Feasible Suppressants When Feasible Proper Road Maintenance

Table 4-15 BACT Determination for Cooling Tower

Pollutant	Emission Limit	Control Device
PM ₁₀ Drift	0.05 lb-drift/hr	0.0005% Drift Eliminators

Table 4-16 BACT Determination for Auxiliary Boiler

Pollutant	Emission Limit	Hours of Operation per year
PM/PM ₁₀	0.007 lb/MMBtu (filterable)	500
SO ₂	0.006 lb/MMBtu	500
NO _x	0.036 lb/MMBtu	500
CO	0.037 lb/MMBtu	500

Table 4-17 BACT Determination for Fire Pump

Pollutant	Emission Limit	Hours of Operation per year
PM/PM ₁₀	0.0019 lb/MMBtu (filterable)	500
SO ₂	0.0006 lb/MMBtu	500
NO _x	0.1 lb/MMBtu	500
CO	0.084 lb/MMBtu	500

By employing the selected technologies, Cash Creek will achieve emission rates that will be equal to or more stringent than the lowest emission rates for existing and proposed coal fired and IGCC generating units.

5. AIR QUALITY IMPACT ANALYSIS

Pursuant 401 KAR 51:017 Section 12, the applicant has provided an analysis of ambient air quality in the area that the proposed facility will affect for each regulated pollutant for which a NAAQS has been established and for which there will be a significant net emissions increase. The Division has not required the application to include an air quality impact analysis for ozone. Pursuant to 401 KAR 51:017 Section 7(5) (a), the Division may exempt a project that would result in a net emissions increase of less than 100 tpy of VOCs from an ambient air impact analysis, including the gathering of ambient air quality data. Also, the Division will follow EPA's current guidance allowing PM₁₀ as a surrogate for PM_{2.5} until the finalization of the PM_{2.5} NSR implementation rules.

The purpose of these analyses is to demonstrate that allowable emissions from the proposed project will not cause or contribute to air pollution in violation of:

- (1) A national ambient air quality standard in an air quality control region; or
- (2) An applicable increment over the baseline concentration in an area.

The proposed facility will have potential emissions in excess of the significant net emission rates for nitrogen oxides, carbon monoxide, sulfur dioxide, and PM₁₀. It should be noted that the steady-state normal operation of the proposed facility does not trigger a full impact air quality analysis of any of these pollutants. However, it is necessary to consider emissions during a cold start-up since this represents the worst-case scenario for emissions. When considering start-up emissions, the only pollutant that is predicted to be above its Significant Impact Level is SO₂ for its 24-hr averaging period. Start up from a cold start takes approximately 48 hours and natural gas is used to preheat the unit during the first 33 hours and these emissions are vented to the Thermal Oxidizer. Start up modeling was used to determine the impacts of the second 24 hour period of start up. See Table 5.1 below for the modeled emissions during the 48 hour start up period from the initial application.

Table 5-1 Startup Emissions (Thermal Oxidizer Modeled)

Pollutant	Startup Emissions Lbs/hr	Startup Emissions Tons/year
PM ₁₀	6.38*	27.94
CO	70.25	307.69
NO _x	117.0	512.46
SO ₂	200.88	879.85

* = Total PM₁₀ (includes condensable)

5.1 Modeling Methodology

The application for the proposed source contains AERMOD air dispersion modeling analysis for criteria pollutants (NO_x, SO₂, PM₁₀ and CO) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b) (2).
2. The Significant Air Quality Impact levels (SAI) found in 401 KAR 51:017, Section 7(5).
3. The PSD Class I and Class II increments found in 401 KAR 51:017, Section 2.
4. The National Ambient Air Quality Standards (NAAQS) found in 401 KAR 53:010, Ambient air quality standards.

All applicable ambient air quality concentration values are presented in Table 5-1. Based on U.S. EPA procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant ambient impacts or SAI. The SAI levels determine if the applicant will be required to perform pre-construction monitoring. If the modeled impacts equal or exceed the SAI levels, pre-construction monitoring may be required. As shown in the application, the modeled

impacts as compared to the SAI levels were not exceeded for, NO_x, CO, PM₁₀ and SO₂. All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. See Sections 6, 7, and 9 of the permit application for details on meteorological, terrain, and land use/land cover (LULC) data selection and modeling methodology.

Therefore, applicant is exempted from the pre-construction ambient monitoring data requirements since the impacts are shown to be below the SAI.

Table 5-2 Ambient Table

POLLUT ANT	AVERAGING PERIOD	SIL (µg/m ³)	SAI (µg/m ³)	PSD CLASS II INCREMENTS (µg/m ³)	NAAQS (µg/m ³)
NO _x	Annual	1	14	25	100
PM ₁₀	Annual 24-HOUR	1 5	NA 10	17 30	50 150
CO	8-hour 1-hour	500 2000	575 NA	NA NA	10000 40000
SO ₂	Annual 24-hour 3-hour	1 5 25	NA 13 NA	20 91 512	80 365 1300

The Division reviewed the air permit application and associated air dispersion modeling, determined the location of the existing monitors, quality of the data, and the data's correctness all met the requirements listed in the NSR guidance manual. Therefore, the applicant is exempted from the pre-construction ambient monitoring data requirements.

5.2 Modeling Results

5.2.1 Class II Area Impacts

As indicated below, the only pollutant that exceeds its Significant Impact Level is SO₂ for the 24-hour averaging period. No pollutants are predicted to exceed their respective Significant Ambient Impact.

Table 5-3 Applicants Modeled Predicted Impacts

POLLUT ANT	AVERAGING PERIOD	SIL (µg/m ³)	SAI (µg/m ³)	MAX IMPACT OF EMISSION (µg/m ³)
NO ₂	Annual	1	14	0.438
PM ₁₀	Annual 24-hour	1 5	NA 10	0.3085 3.99
SO ₂	Annual 24-hour 3-hour	1 5 25	NA 13 NA	0.835 10.22 21.14
CO	8-hour 1-hour	500 2000	575 NA	37.99 61.69

As shown in the table below, the impact of SO₂ emissions will not cause a violation of the NAAQS or exceedance of the applicable increment.

Table 5-4 Refined Modeling Results

POLLUTANT	AVERAGING PERIOD	NAAQS (µg/m ³)	CLASS II PSD INCREMENT (µg/m ³)	MAX IMPACT – ALL SOURCES (µg/m ³)/INCREMENT CONSUMPTION
SO ₂	24-hour	365	91	150.28 20.20

Based on the analysis performed by the source, the emissions from the proposed source will not cause an exceedance of the NAAQS or a violation of the applicable Class II Increment.

5.2.2 Class I Area Impacts

The purpose of the Class I impact analysis is to predict the the impacts of SO₂, PM₁₀, and NO_x emissions as well as the total deposition of nitrogen and sulfur, and the effect on visibility in Mammoth Cave National Park (MCNP). The park is 116 KM southeast of the proposed project and is designated as a Federal Class I area.

The CALPUFF modeling suite was used to predict concentrations in MCNP. Section 9 of the permit application entitled CLASS I ANALYSIS explains, in detail, the modeling methodology employed to estimate the impact on the park. The results (tables 9-8 and 9-9 of the application indicate the none of the applicable Significant Impact Levels will be exceeded. Therefore a cumulative analysis is not required pursuant to Federal guidance. The conclusion is that there will be no significant impact on the park due to the construction and operation of the proposed source.

Table 5-5 Class I Modeling Results - Normal Operations

	PROPOSED CLASS I SIL	1990	1992	1996
VISIBILITY CHANGE	RH_{max}	95.00%	95.00%	95.00%
24 HR MAX	5%	1.99	2.56	3.59
>5%		0	0	0
>10%		0	0	0
PM_{10 total} IMPACT - ug/m3				
24 HR MAX	0.2	0.0507	0.0652	0.0936
ANNUAL MAX	0.3	0.0036	0.0037	0.0040
SO₂ IMPACT - ug/m3				
3 HR MAX	1	0.1101	0.1278	0.1585
24 HR MAX	0.2	0.0338	0.0393	0.0519
ANNUAL MAX	0.1	0.0021	0.0021	0.0025
NO_x IMPACT - ug/m3				
ANNUAL MAX	0.1	0.0040	0.0037	0.0044
TOTAL S - ug/m2/s		5.29E-06	4.47E-06	7.45E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0017	0.0014	0.0023
BACKGROUND KG/HA/YR	16.99			
PERCENT CHANGE	%	0.010%	0.008%	0.014%
TOTAL N - ug/m2/s		5.48E-06	4.70E-06	6.22E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0017	0.0015	0.0020
BACKGROUND KG/HA/YR	20.65			
PERCENT CHANGE	%	0.008%	0.007%	0.009%
PM10 TOTAL ANALYSIS				
PMF				
24 HR MAX		3.60E-02	4.57E-02	6.37E-02
ANNUAL MAX		2.55E-03	2.61E-03	2.88E-03
EC				
24 HR MAX		3.61E-04	4.58E-04	6.39E-04
ANNUAL MAX		2.55E-05	2.62E-05	2.88E-05
SOA				
24 HR MAX		4.34E-03	5.52E-03	7.69E-03
ANNUAL MAX		3.07E-04	3.15E-04	3.47E-04
SO₄				
24 HR MAX		1.01E-02	1.36E-02	2.16E-02
ANNUAL MAX		7.09E-04	7.32E-04	7.71E-04
PM_{10(total)}				
24 HR MAX		5.075E-02	6.524E-02	9.362E-02
ANNUAL MAX		3.59E-03	3.69E-03	4.03E-03

Table 5-6 Class I Modeling Results - Startup

	PROPOSED CLASS I SIL	1996** STARTUP - INCREMENTAL
VISIBILITY CHANGE	RH_{max}	95.00%
24 HR MAX	5%	3.51
>5%		0
>10%		0
PM_{10 total} IMPACT - ug/m3		
24 HR MAX	0.2	0.0888
ANNUAL MAX	0.3	0.0021
SO₂ IMPACT - ug/m3		
3 HR MAX	1	0.4840
24 HR MAX	0.2	0.1197
ANNUAL MAX	0.1	0.0043
NO_x IMPACT - ug/m3		
ANNUAL MAX	0.1	0.0045
TOTAL S - ug/m2/s		8.85E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0028
BACKGROUND KG/HA/YR	16.99	
PERCENT CHANGE	%	0.016%
TOTAL N - ug/m2/s		5.02E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0016
BACKGROUND KG/HA/YR	20.65	
PERCENT CHANGE	%	0.008%
PM10 TOTAL ANALYSIS		
PMF		
24 HR MAX		5.53E-02
ANNUAL MAX		1.43E-03
EC		
24 HR MAX		5.49E-04
ANNUAL MAX		1.39E-04
SOA		
24 HR MAX		5.37E-03
ANNUAL MAX		1.35E-04
SO₄		
24 HR MAX		2.76E-02
ANNUAL MAX		3.48E-04
PM_{10(total)}		
24 HR MAX		8.882E-02
ANNUAL MAX		2.05E-03

6. ADDITIONAL IMPACTS ANALYSIS

401 KAR 51:017 Section 13 requires an applicant for a PSD permit to provide an analysis of the impairment to visibility, soils and vegetation that will occur as a result of the project and projected growth associated with the project.

6.1 Growth Analysis

As reported in the application, the proposed project will employ additional personnel that will peak at 1000 during the construction phase. The project will also employ 200-300 people on a permanent basis. It is a goal of the project to hire from the local community where possible. The proposed project is expected to result in an increase in residential and commercial growth in the vicinity of the plant. This increased economic activity will result in secondary air emissions (increased vehicular use) but is not expected to significantly impact air quality.

6.2 Soils and Vegetation Impacts Analysis

The proposed project is located on Kentucky State Highway 1078 in Henderson County. Impacts on the soil types and vegetation due to Cash Creek's air emissions were evaluated using EPA Document EPA-450/2-81-078 *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*. Predicted ambient concentrations due to the project are below the NAAQS and PSD increments and no significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

6.3 Visibility Impairment

The National Forest Service (NFS) was contacted to identify Class II areas for visibility concerns. Ms. C. Huber of the NFS informed the Division that they would not require a VISCREEN (computer model) analysis, as the nearest area managed by the NFS, the Land between the Lakes National Recreation Area is over 50 km from Henderson County.

After the Division's consultation with the NFS, areas of concern for visibility were not identified, so the Division was not required to perform a visibility analysis. Thus, a Class II Visibility Analysis was not performed.

Section 7, ADDITIONAL IMPACT ANALYSIS, of the application contains a complete analysis of additional impact on soils and vegetation, secondary growth and Class II visibility that are all addressed in this section. The Division deems this analysis to be adequate to demonstrate that the construction and operation of the Cash Creek facility will not cause significant environmental impact.

7. CONCLUSIONS AND RECOMMENDATIONS

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed project meets all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR 60, 61 and 63 will also be met.
2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels. No adverse impact is expected on any Class I area.
3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

A draft permit to construct and operate a nominal 770 megawatt (MW) electric generating facility using Integrated Gasification Combined Cycle (IGCC) located southwest of Owensboro, Kentucky, in Henderson County, Kentucky containing conditions which may

ensure compliance with all the applicable requirements listed above has been prepared by the Division and issued for public notice and comment. The Division recommends the issuance of the final permit following the public notice period, and after the resolution of any adverse comments received by the Division. A copy of this preliminary determination will be made available for public review at the following locations:

1. Henderson County Clerk's office, 20 N. Main St, Henderson, KY 42420.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Owensboro Regional Office, 3032 Alvey Park Drive, Suite 700, Owensboro, KY 42303 .